



May 30, 2009

Posted on AESO website

Fort Nelson Rate FTS Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Fort Nelson Rate FTS Working Group

The first meeting of the Fort Nelson Rate FTS Working Group for the AESO's 2010 tariff application is scheduled as follows:

Time: 2:00 to 4:00 PM
Date: Monday, June 1, 2009
Location: Meeting Room 2538, AESO Office, 330 – 5th Avenue SW, Calgary
Refreshments: Coffee, juice, and soft drinks

This working group includes the following members:

- AltaLink: Hao Liu
- BC Hydro: John Rich, Yvette Maiangowi, Fred James, or Lewis Manning
- Harvest: Dale Hildebrand
- IPCAA: Sheldon Fulton
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

- 1 Introductions** 2:00 PM
 - Please indicate which stakeholders you represent
- 2 Review agenda** 2:10 PM
- 3 Review draft working groups terms of reference** 2:15 PM
 - See enclosed document originally posted on April 22, 2009
 - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
 - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.

- A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.
- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for Fort Nelson Rate FTS 2:20 PM

- Please review the enclosed information before the meeting, if possible:
 - (a) History of service to Fort Nelson from 1990 to 2000, as summarized by BC Hydro in Exhibit “B” of its evidence in the AESO’s 2005-2006 General Tariff Application proceeding, filed on March 11, 2005
 - (b) Discussion of the Fort Nelson rate in section 5.7 (pages 30-33) of Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
 - (c) Excerpts from Volume I (pages 21-22 and 38-40) of the AESO’s Northwest Alberta Transmission Development Need Identification Document dated March 7, 2006 (available in its entirety on www.aeso.ca by following the path Transmission ► Need Applications ► Approved ► Northwest Alberta Transmission Development, as the 4th link titled “Northwest Alberta Transmission Development Need Identification Document - Volume I”)
 - (d) Section 5 (Electricity Supply and Relevant Market Forecasts) and section 6 (Planning Horizon Resource Options) of the Fort Nelson Appendix N1 to BC Hydro’s 2008 Long Term Acquisition Plan as updated on October 24, 2008 (available in its entirety on www.bcuc.com by following the path Current Applications ► BC Hydro - 2008 LTAP ► B-1-10, in the “Exhibits” section)
- Is there other background that participants consider particularly relevant?

5 Scope for Fort Nelson Rate FTS Working Group 2:30 PM

- Long-term load considerations in the Rainbow Area (including Fort Nelson)
- AESO obligations with respect to service to Fort Nelson
- Impacts of service to Fort Nelson with respect to:
 - TFO (capital and operating) costs,
 - ancillary services (TMR) costs, and
 - pool price
- Rate design principles for service to Fort Nelson
- Specific features of Fort Nelson Rate FTS to be proposed in AESO’s 2010 tariff
- Working group will not review or discuss Interim Refundable Fort Nelson Rider H, as the intent is to develop a principle-based and sustainable replacement for that rider

6 AESO obligations with respect to service to Fort Nelson 2:45 PM

- The Electric Utilities Act requires the AESO to plan the transmission system to meet the needs of Alberta (as expressed in sections 33 and 34(1), for example)
- The rate charged to BC Hydro at Fort Nelson must be just and reasonable
 - How should justness and reasonableness be assessed?

7 Impacts of service to Fort Nelson 3:15 PM

- TFO (capital and operating) costs
- Ancillary services (TMR) costs
- Pool price, including Dispatch Down Service (DDS) impacts

- | | | |
|----|---|---------|
| 8 | Follow-up required for next meeting <ul style="list-style-type: none">• Summarize what tasks need to be completed before next meeting and who will complete them | 3:50 PM |
| 9 | Dates and times for next meeting(s) | 3:55 PM |
| 10 | Adjourn | 4:00 PM |

This agenda and all other printed information related to the Fort Nelson Rate FTS Working Group is available on the AESO's website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders' participation in this consultation.

If you have any comments or questions on this consultation process or the AESO's tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO

AESO 2010 Tariff Consultation Working Groups Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO's 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO's 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

- (a) **POD Cost Function and Investment Level Update**
 - Substations included in POD cost data set
 - Inflation index to escalate POD cost data to 2010
 - Multiplier to determine investment level
- (b) **TFO O&M Cost Causation Study**
 - Respond to AUC directions on analysis of TFO O&M costs
 - Determine if TFO O&M costs are energy-related
 - Determine if TFO O&M costs should be functionalized similarly to capital costs
- (c) **DTS Operating Reserve Charge Design**
 - Methodology to analyze and assess design of operating reserve charge
 - Criteria for selection of appropriate design for operating reserve charge
- (d) **Fort Nelson Rate FTS**
 - Rate design principles for Fort Nelson and similar services
 - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
 - Contractual considerations for Fort Nelson and similar services
- (e) **Export and Import Rates XTS and ITS**
 - Rate design principles for higher-priority export and import services
 - Similarities and differences between domestic and intertie services
 - Potential allocation of "deep system" costs to services over merchant interties
- (f) **Deferral Account Riders B and C**
 - Rate design principles for deferral account riders
 - Practicality of improving allocation accuracy of deferral account riders
 - Possible integration of Riders B and C

- (g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
 - Common provisions that could be standardized and consolidated
 - Dispersed information that could be consolidated
- (h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
 - Potential provisions for amortized customer contribution option
 - Assessment of credit-worthiness and mitigation of risk of default
- (i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
 - Assessment of Primary Service Credit and associated investment factor
 - Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.

- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.

- (a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.
- (b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.
- (c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.
- (d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.
- (e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

- (a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.
- (b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.

- (c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO's mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO's tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- AUC Decision 2008-037: AESO 2007 General Tariff Application Refiling (released on May 8, 2008)
- EUB Decision 2007-106: AESO 2007 General Tariff Application (released on December 21, 2007)
- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
- EUB Decision 2005-131: AESO Refiling of 2005/2006 General Tariff Application per Decision 2005-096 (released on December 6, 2005)
- EUB Decision 2005-096: AESO 2005/2006 General Tariff Application (released on August 28, 2005)

Exhibit "B"

Historic service to Fort Nelson can be summarized as follows:

- Pre-1991, Fort Nelson, B.C. was served by BC Hydro through a non-integrated distribution system with power generated by a diesel generating station.
- May 1990 – Wescup agreed to construct/own and operate transmission facilities in B.C. to permit the sale and delivery of electric energy by Wescup to BC Hydro.
 - APL built and Wescup paid for and was owner of the BC facilities (105 km long at a cost of 15.6 million).
- May 1990 – APL entered into an electricity sale agreement with Wescup to supply electricity from the Alberta interconnected electric system to Wescup for resale to BC Hydro (the "ESA"). Energy was supplied on an interruptible basis. The term of the ESA was 20 years.
- November 1990 – The Energy Resources Conservation Board approved the interconnection of APL facilities with the Wescup facilities.
- 1991 – APL constructed the interconnection facilities in Alberta (65 km long at a cost of \$4.3 million).
 - Wescup paid a capital contribution towards the construction of the Alberta facilities of \$782,000.
 - December 1991 - In Decision E91095, the Board found that since Wescup effectively took delivery of electric energy in Alberta, it was an Alberta customer.
- May 1993 - In Decision E93035, the Board approved APL's proposal to charge a special facilities charge to Wescup through a rate rider ("Rider E"). The facilities charge was approved on the basis that it was consistent with treatment of other APL customers assessed a special facilities charge.
- 1999 – the Board approved the sale by Wescup of its system to BC Hydro.
- 1999 – the Board approved ATCO Electric's GTA, including the flow-through of the TA's opportunity service to BC Hydro and Rider E (the facilities charge). Service continued to be supplied on an interruptible basis.
- 2000 – Trans Alta Energy constructed a gas fired generating station near Fort Nelson. BC Hydro contracted to buy all of the energy from the generating station. BC Hydro still required back up for its load at Fort Nelson. After being told by ATCO Electric that it would not provide firm back-up service to BC Hydro, BC Hydro made inquiries of the TA about receiving firm service directly.
- July 2000 – ATCO Electric and AESO concluded an agreement to allow the TA to provide a firm back-up service directly to BC Hydro.
- Spring/Summer 2000 - Powerex contracted for STS service from the TA at the Alberta/BC border. July 2000 - BC Hydro contracted for DTS service from the TA at the Alberta/BC border.

The Board agrees with the AESO that the proposed reduction in ratchet term to two years provides a reasonable balance between customer flexibility and revenue stability. The AESO's proposal is therefore approved, subject to the direction contained above that no ratchet will apply to bulk wires costs.

5.5.4 Standby Tariffs

The Application did not contain a specific proposal for a standby rate. The AESO noted that it had commenced discussions with customers with respect to the development of such a rate and suggested that a standby rate may offer some relief to the low load factor customers most impacted by changes to the DTS rate. The AESO proposed to engage in additional customer consultation on rate design immediately after the decision on its 2006 tariff application is issued in preparation for filing its 2007 application.

The Board notes that EnCana and TransAlta supported the development of rates for low load factor or standby customers, and were specifically supportive of the discussion of such a rate in consultations proposed by the AESO for its 2007 tariff. ADC and IPCAA also supported the development of such a rate as a means to ameliorate the effect of their DTS rate proposals.

The Board agrees with the parties that the development of a standby rate would be appropriate and may offer some flexibility to low load factor customers. However, the Board cautions parties that such customers impose significant costs with respect to the local system and POD costs and therefore, they must remain responsible for those costs. The Board has no specific directions with respect to stand-by rates, however.

5.6 Supply Transmission Service Rate (STS)

The Board notes that the AESO did not specifically comment upon the design of the STS rate in Section 4 of the Application nor did any party comment upon it in argument or reply.

The Board notes that the *Transmission Regulation* has had the effect of shifting all wires costs to load. The only significant cost left for supply customers is line losses. This has been appropriately reflected in the design of the STS rate proposed in Section 7 of the Application. The rate is approved as filed.

5.7 Fort Nelson BC Rate

The AESO explained its rate proposal respecting its proposed Fort Nelson Demand Service (FDS) Rate as follows:

The AESO has examined the Fort Nelson arrangement in light of its history and current circumstances, and has decided to not re-apply for the approval of the Fort Nelson Settlement. Instead the AESO has determined that the treatment of BC Hydro and Powerex under DTS and STS contracts respectively as set out in the Settlement is inappropriate for the following reasons:

- (a) Current DTS and STS rates are intended for service to Alberta customers. BC Hydro and Powerex are not Alberta customers.
- (b) The current DTS contract does not appropriately reflect the type of services provided to BC Hydro and Powerex, nor does it reflect the principles set out by

the EUB in Decision E91095 to recover the incremental cost burden to Alberta so that Albertans do not subsidize BC through serving Fort Nelson.

- (c) The provision of ancillary services (especially transmission must run, or TMR, services) as well as the treatment of losses has developed well beyond the levels that existed at the time the original Fort Nelson Settlement was entered into in July 2000.

The AESO therefore proposes to terminate the DTS contract with BC Hydro and replace it with a load contract for a specific Fort Nelson Demand Transmission Service (FDS) rate, and to terminate the STS contract with Powerex and replace it with an import opportunity contract under the standard IOS rate. The FDS rate is intended to recover the costs associated with the demand services provided to Fort Nelson, while the IOS rate will recover the costs associated with the import services provided.⁴⁹

The AESO proposes to charge Fort Nelson a customized DTS rate and an Import Opportunity Service (IOS) rate that would include:

- (i) the forecast cost to be incurred by ATCO Electric to supply the transmission line to Fort Nelson;
- (ii) a transmission must run (TMR) cost that is based upon TMR dispatched from Fort Nelson and standby TMR from Alberta;
- (iii) the losses attributable to the Fort Nelson generator; and
- (iv) the charges to recover general and administrative costs attributable to Fort Nelson.

The largest charge would be the TMR costs which were forecast to be \$6 million for 2006.

In argument, the AESO continued to maintain that Fort Nelson was not eligible for the postage stamp DTS rate, arguing that it did not fall under Subsection 30(3) of the *Electrical Utilities Act* (EUA) and that the FDS rate fairly reflected the cost of providing service to Fort Nelson. The AESO also argued that the large increase in costs to Fort Nelson did not constitute rate shock as it would only increase British Columbia Hydro and Power Authority's (BCH) total costs by 0.25%. In reply, the AESO did not dispute that it had an obligation to serve the Fort Nelson load, but maintained it had a corresponding responsibility to recover the costs of such service. FIRM supported the AESO's argument.

In its intervener evidence, BC Hydro (BCH) strongly opposed the AESO's proposal, stating that it was discriminatory, unfair and failed to consider value of service. BCH noted that its costs would rise by approximately 2800%, an increase constituting rate shock of a magnitude imposed upon no other DTS customer. BCH maintained that it had historically been treated as an Alberta customer and stated as such it should continue to receive non-discriminatory access to the same postage stamp DTS and STS service as any other Alberta customer, regardless of the estimated individual incremental cost.

In argument, BCH stated that the AESO had an obligation to continue to serve Fort Nelson and such service should be provided under the DTS rate. BCH maintained that the AESO had presented no evidence that the EUA allowed it to discriminate against customers such as Fort Nelson due to its location. In the event that Fort Nelson was determined by the Board to not qualify as an Alberta customer eligible for the DTS rate, BCH submitted that service should be

⁴⁹ Application. Section 4, page 19

provided on an incremental cost basis, which it described as inherently unstable and difficult to calculate. In particular BCH stated⁵⁰:

As Mr. Stout made clear⁵¹, if the AESO wants to ignore BC Hydro's status as a customer on the basis that the ultimate load is outside Alberta, then, logically, it must look at the total consequence of the service provided to and obtained from the territory it has determined to be foreign. In other words, if it wishes to employ an incremental analysis, it must look at the incremental effect of Fort Nelson generation, as well as Fort Nelson load. If that is done, there can be no doubt that the relative efficiency of the Fort Nelson generation introduces a substantial benefit to the Rainbow Lake area and significantly diminishes the cost of providing transmission must run ("TMR") within that area of northwest Alberta.

The AESO's calculation of the costs of serving Fort Nelson load significantly exaggerates the actual incremental cost of serving by inappropriately combining a calculation of some embedded historical costs with a flawed calculation of gross incremental costs of service to serve the Rainbow Lake area.

Specifically, the AESO has included in what it calls incremental costs, wires costs that are not incremental in any normal sense of that word's use in cost studies.⁵² As Mr. Stout testified, these costs represent a non-averaged wires cost directly allocated to Fort Nelson but not to any other radial line customer.⁵³ In addition, the AESO has also declared the \$455,000 contribution towards fixed costs to be an incremental cost of serving Fort Nelson, and yet admits that such contribution towards fixed costs would simply be reallocated to other Alberta load in the event that Fort Nelson were no longer integrated with the AESO system.⁵⁴ This contribution, like the wires costs, forms no proper part of an incremental cost study because they are sunk or embedded costs which would remain even if the Fort Nelson load were no longer present. A truly incrementally-based rate would not include these costs.

The Board rejects BCH's argument that it should continue to receive service under the DTS rate. The Board cannot ignore the obvious – Fort Nelson is not located in Alberta. As such, the Board does not consider that the AESO is obliged to offer the postage stamp service that it is obligated to provide to Alberta customers.

Equally, however, the Board considers that the rate charged to BCH for Fort Nelson service must be just and reasonable, in accordance with established regulatory principles. The Board does not consider that the proposed FDS rate conforms to these principles. The Board also believes that the rate charged for Fort Nelson service must be designed in such a manner that it will provide a fair and reasonable template that can be used in determining rates for other inter-provincial service, be it service provided by the AESO to other BC customers or by BCH to customers located in Alberta. The Board does not consider the AESO's proposal to be either just or reasonable.

⁵⁰ BCH argument, page 8

⁵¹ Transcript Volume 7 at page 1678, line 6 to page 1679, line 16; see also Transcript Volume 7 at page 1719, line 5 to page 1722, line 22.

⁵² Transcript Volume 7, page 1682, lines 7-13.

⁵³ Transcript Volume 7, page 1702, line 17 to page 1703 line 13.

⁵⁴ See Exhibit 02-020 at BCH.AESO-006(a).

The Board notes that the largest single element in the proposed FDS rate is the allocation of TMR costs. The Board agrees with BCH that the AESO has not provided a sufficient basis for this charge. In particular, the Board does not consider that there is sufficient evidence that the AESO has considered the real value of Fort Nelson generation to Alberta customers.

The Board also notes the proposed \$455,000 charge for contribution to fixed costs. The Board does not consider this charge has been justified on the basis of a reasonable allocation of actual costs.

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. the postage stamp rate for bulk wires costs;
2. the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;
3. the postage stamp rate for the AESO's own costs and other industry costs; and
4. the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.

The Board does not consider it necessary to charge a POD related cost as BCH provides its own facilities. Correspondingly, BCH should not be eligible for the PSC credit in the future as it will not be charged for POD services.

The STS service provided to Fort Nelson should continue to be charged at the full postage stamp rate plus a losses charge to be determined by the AESO, in the same manner as it would for an Alberta generator.

Both DTS and STS services provided to Fort Nelson should continue to be subject to the usual deferral account treatment, similar to that of any other customer.

The Board considers the above will result in just and reasonable charges for service to Fort Nelson. The Board also considers that this provides a reasonable template for the provision of other inter-provincial services as well. The AESO's proposed tariff treatment of Fort Nelson is denied and the AESO is directed to continue to provide DTS and STS services to Fort Nelson on the basis set out above and the refiling should demonstrate this treatment.

5.8 Export Rates

5.8.1 Firm Export/Import Rates

In Decision 2002-099, the Transmission Administrator's (TA) Congestion Management Decision, the Board directed the TA to "...further investigate whether a firm import/export service could be offered over the existing B.C. Tie with a level of "firmness" acceptable to prospective import/export customers".

In response to this directive, the AESO submitted that it began contacting its customers active in importing and exporting in the spring and summer of 2004. On September 23, 2004, the AESO published an *Alberta Import/Export Tariff* discussion paper to broaden consultation with stakeholders. The paper was presented at a stakeholder conference on October 6, 2004 followed by written comments from six stakeholders. Discussion was also held at a December 3, 2004

4.2.1 Detailed Description of the Concepts

a) Concept 2 (Preferred Concept)

Concept 2 is a full transmission concept and when Phase 1 is completed in 2009, the Rainbow Lake area will not rely on any TMR generation. The component additions recommended in this concept can be staged into two phases, Phase 1 (2007 & 2009) and Phase 2 (2014).

2007 Additions:

Shunt capacitors are proposed at Goodfare 815S and Big Mountain 845S in the Grande Prairie area to maintain the system voltages during normal and contingency conditions. Shunt capacitors are also proposed at Ksituan River 754S and Friedenstal 800S to provide reactive power support. A Static VAR Compensator (SVC) at Cranberry Lake (827S) is also proposed to provide dynamic VAR support to 7L61, 7L63 and 7L12. Shunt capacitors are also proposed at Lubicon 780S and Little Smoky 813S. The proposed reactive power support in the Grande Prairie and Peace River areas prevents the voltage collapse in Area B under the contingency of Poplar Hill unit (refer to Row 3 of Table 3.1-1) as well as Need Identification Results, Volume II.

The need studies have shown the requirement of the second transformer (Table A2, Figure A-2K in Need Identification Results, Volume II). ATCO Electric has a spare 240/144 kV 120/160/200 MVA transformer available at Louise Creek 809S. It is therefore recommended that this transformer should be put in service at Louise Creek 809S by 2007.

2009 Additions:

A 240 kV Brintnell 876S to Wesley Creek 834S line is proposed to bring power from Fort McMurray area to the Northwest. This transmission line provides strong voltage support at Wesley Creek 834S which now acts as a sending node for power to Rainbow Lake and High Level areas. With the addition of this 240 kV line, the outage of 9L11 Little Smoky 813S to Wesley Creek 834S is no longer a critical contingency. A 144 kV double circuit from Wesley Creek 834S to Hotchkiss 788S provides capacity as well as reliability to the system north of Wesley Creek.

In the Rainbow Lake and High Level areas, a 144 kV line is proposed from Ring Creek 853S to Rainbow Lake 791S and another line is

proposed from Sulphur Point 828S to High Level 786S. This will result in Rainbow Lake-Ring Creek-Keg River and Keg River-High Level-Sulphur Point 144 kV closed loops. In the absence of generation in the Rainbow Lake area, the closing of the High Level 786S to Sulphur Point 829S and Ring Creek 853S to Rainbow Lake 791S 144 kV loop helps in providing voltage support and also provides capacity during contingency conditions. The removal of generation from the Rainbow Lake and Fort Nelson areas will result in low short circuit levels in the area. For this reason, a synchronous condenser is recommended in the Rainbow Lake area to provide reactive power support as well as improve the short circuit levels. A SVC at High Level 786S will provide voltage control under normal and contingency conditions.

The 919L and 989L Sundance to Sagitawah 240 kV lines provide power from the Wabamun area into the Northwest region. In the 2009/10 scenario and beyond, the loading on each of these two circuits will increase to well over 300 MW. Therefore, a SVC at Little Smoky 732S is proposed to maintain voltages during contingencies of 919L, 989L or the proposed 240 kV Brintnell to Wesley Creek line.

This development in the Rainbow Lake and High Level areas along with the Brintnell 876S to Wesley Creek 834S to Hotchkiss 788S lines will address the need in Area A as mentioned in Section 3.0. The Brintnell 876S to Wesley Creek 834S 240 kV line also helps in deferring the need in Area C from 2011/12 (refer to Row 7 in Table 3.1-1) to 2014. The proposed development also eliminates the use of TMR from the Rainbow Lake area. However, the AESO will continue to maintain the long term TMR contracts in the Grande Prairie and Valleyview areas in order to provide only reactive power support.

2014 Additions:

A 240 kV line from Bickerdike 39S to Little Smoky 813S is proposed to provide the additional feed into the Northwest region as the proposed Brintnell 876S to Wesley Creek 834S line will not be adequate in the longer term to meet the load in the southern part of the region. This new line will provide relief to 989L and 919L by reducing the loading on these two circuits thus improving the voltage stability limit identified earlier.

b) Other Full Transmission Concepts Considered

Concept 1

Concept 1 is similar to Concept 2 except in the Rainbow Lake and High Level areas where a single circuit 144 kV line is proposed from

Details regarding the multiple variable analysis and methodology are provided in Appendix G and the Alternative Assessment Methodology, Volume II, respectively.

c) Impact of Changing System Conditions

As previously noted, the AESO has based its recommendation primarily on the non-financial benefits that Concept 2 provides over the other concepts and has considered the financial results in balance with these other benefits. The base financial results indicate that the relative loss benefits are a significant factor in determining the total net benefit of the concepts. The base analysis indicates that Concepts 1 and 3 are more favorable in total than Concept 2 primarily due to the loss benefits. Conversely, Concept 4 shows less favorable results than Concept 2 due to the cost of losses.

Due to this reliance on loss benefits and costs to render the other concepts more or less favorable than Concept 2 the AESO has performed the following analysis to test the sensitivity of these benefits under changing system conditions that may affect the Northwest.

The following analysis has been based on a more simplified calculation. For this purpose the winter peak load losses for the complete Alberta system were multiplied by the square of the load factor of the system which was considered to be 0.79 to calculate the approximate average system losses for the whole year. This approach was adopted to expedite the calculation of the losses for the purpose of this specific analysis.

i) Changing Load in the Rainbow Lake Area

The AESO has tested the sensitivity of loss benefits in relation to changes in load in the Rainbow Lake area. Specifically, this includes the potential decline of the Husky processing plant load (35 MW) and of the Fort Nelson, BC load (25 MW).

Husky has informed the AESO that its load located at Rainbow Lake will start to decline after the 2010 timeframe. The AESO confirmed this independently through a report, referred to as the Stantec Report, which it published on the AESO website in August 2005. For further information regarding this report, please refer to Appendix C.

Similarly the load at Fort Nelson, BC may change in the event that BC Hydro decides to serve this load through some internal means (generation, transmission, etc.) rather than from Alberta. The AESO has assumed Fort Nelson as a firm load in its base analysis as it is

obligated to serve Fort Nelson under the DTS contract with BC Hydro. It is important to note that in discussions with BC Hydro, the AESO has not had any indications about the decline of Fort Nelson load.

The following analysis shows the impact on the concepts with no load at the Husky processing plant or at Fort Nelson, BC.

Table 5.2.5-3: Base Analysis: With Fort Nelson & Husky Load - Better Than (Worse Than) Concept 2

| 20-Year PV | Concept 1 | Concept 2 (Preferred Concept) | Concept 3 | Concept 4 | Concept 2H | Concept 3H | Concept 4H |
|--------------|--------------|-------------------------------|--------------|----------------|----------------|---------------|----------------|
| Wires | (\$2M) | \$0M | (\$31M) | \$6M | \$35M | (\$25M) | \$41M |
| Losses | \$43M | \$0M | \$54M | (\$19M) | \$22M | \$98M | \$14M |
| TMR | \$0M | \$0M | \$0M | \$0M | (\$68M) | (\$68M) | (\$68M) |
| TOTAL | \$41M | \$0M | \$23M | (\$13M) | (\$11M) | (\$5M) | (\$13M) |

Table 5.2.5-4: Scenario: Fort Nelson & Husky Load Removed - Better Than (Worse Than) Concept 2

| 20-Year PV | Concept 1 | Concept 2 (Preferred Concept) | Concept 3 | Concept 4 | Concept 2H | Concept 3H | Concept 4H |
|--------------|-------------|-------------------------------|---------------|----------------|----------------|----------------|----------------|
| Wires | (\$2M) | \$0M | (\$31M) | \$6M | \$35M | (\$25M) | \$41M |
| Losses | \$6M | \$0M | \$28M | (\$16M) | \$9M | \$43M | \$3M |
| TMR | \$0M | \$0M | \$0M | \$0M | (\$68M) | (\$68M) | (\$68M) |
| TOTAL | \$4M | \$0M | (\$3M) | (\$10M) | (\$24M) | (\$50M) | (\$24M) |

To be expected, the most significant impact of this load reduction in the Rainbow Lake area is to Concept 1. The loss benefits of Concept 1 are reduced substantially in relation to Concept 2 with the Husky and Fort Nelson loads removed. Similarly, the loss benefits in Concept 3 are also reduced bringing the total result compared to Concept 2 slightly worse off. Finally, with respect to Concept 4, the cost of losses is reduced given that the loss of load from the Rainbow Lake area

would lessen the pressure from the Wabamun / Edmonton generation source.

ii) Fort Nelson Generation

Although the AESO has assumed Fort Nelson load in its base analysis due to contractual obligations, BC may decide to continue operation of the Fort Nelson generator. The following analysis shows the impact on the concepts of continued generation at Fort Nelson supplying the Rainbow Lake area.

Table 5.2.5-5: Base Analysis: Without Fort Nelson Generation - Better Than (Worse Than) Concept 2

| 20-Year PV | Concept 1 | Concept 2 (Preferred Concept) | Concept 3 | Concept 4 | Concept 2H | Concept 3H | Concept 4H |
|--------------|--------------|-------------------------------|--------------|----------------|----------------|---------------|----------------|
| Wires | (\$2M) | \$0M | (\$31M) | \$6M | \$35M | (\$25M) | \$41M |
| Losses | \$43M | \$0M | \$54M | (\$19M) | \$22M | \$98M | \$14M |
| TMR | \$0M | \$0M | \$0M | \$0M | (\$68M) | (\$68M) | (\$68M) |
| TOTAL | \$41M | \$0M | \$23M | (\$13M) | (\$11M) | (\$5M) | (\$13M) |

Table 5.2.5-6: Scenario: With Fort Nelson Generation - Better Than (Worse Than) Concept 2

| 20-Year PV | Concept 1 | Concept 2 (Preferred Concept) | Concept 3 | Concept 4 | Concept 2H | Concept 3H | Concept 4H |
|--------------|--------------|-------------------------------|-------------|----------------|----------------|----------------|----------------|
| Wires | (\$2M) | \$0M | (\$31M) | \$6M | \$35M | (\$25M) | \$41M |
| Losses | \$15M | \$0M | \$34M | (\$17M) | \$14M | \$62M | \$12M |
| TMR | \$0M | \$0M | \$0M | \$0M | (\$68M) | (\$68M) | (\$68M) |
| TOTAL | \$13M | \$0M | \$3M | (\$11M) | (\$19M) | (\$31M) | (\$15M) |

The effect of continued generation from the Fort Nelson plant is similar to that of the loss of load at Husky and Fort Nelson. Again, Concept 2 maintains its benefits in relation to the other concepts.

1 Possible impacts of future GHG offset costs are analyzed. The GHG emissions of any Fort
2 Nelson gas-fired generation in the analysis are tracked and the volume of carbon dioxide
3 equivalent (**CO₂e**) is measured and the forecast cost of GHG offsets is calculated.

4 The level of CO₂e associated with imports is calculated. Risk analysis is provided with
5 respect to the possible impact of any B.C. Government requirement to offset any GHG
6 emissions that would have been created in Alberta with respect to imported energy to B.C.
7 at Fort Nelson.

8 **4 Stakeholder and First Nations Engagement**

9 With respect to First Nation and stakeholder engagement, refer to Appendix N2
10 (Exhibit B-1-10).

11 **5 Electric Supply and Relevant Market Forecasts**

12 **5.1 Load forecast of BC Hydro Domestic Customers**

13 The Fort Nelson region, as well as the AIES, are generally supplied by thermal generating
14 resources and are capacity constrained and not energy constrained. The combined region
15 of Fort Nelson and Rainbow Lake is also transmission constrained both internally and
16 externally to the AIES.

17 Therefore, the predominant forecast for reliability planning purposes is the peak demand
18 forecast. The primary use of the energy demand forecast is to calculate the forecast cost of
19 service, including local supply, imports and exports.

20 The 2007 Reference Load Forecast and Scenarios identify a medium- to long-term
21 customer load growth potential for up to an additional 60 MW to 70 MW by 2013. This
22 represents an approximately 200 per cent increase from the current firm supply capability of
23 28.5 MW. This load growth is being driven by the development of new industries, primarily in
24 the oil and gas sector. Much of the new load is load that the potential customers could meet
25 by either gas or electric drive systems.

1 The load growth is expected to come from a relatively small number of commercial or
2 industrial customers. As a result the actual names and locations of the facilities and the
3 timing of the new or upgraded facilities are commercially sensitive. This, along with the size
4 of the expected increases relative to the size of the base domestic load, has led BC Hydro
5 to conclude that the best manner of presenting and analysing the various new supply
6 solutions (portfolios) is through the use of load growth Scenarios. To that end, BC Hydro is
7 basing its analysis on its 2007 Load Forecast¹⁰ (**Reference Forecast**) along with three
8 Scenarios of possible load growth. Each of the Scenarios has been developed using a
9 bottom-up forecasting methodology based on information gathered, in confidence, from
10 potential customers and assessed by BC Hydro as to the likelihood of the projects
11 proceeding.

12 BC Hydro formulated three potential load growth Scenarios based on discussions conducted
13 in 2007 with several B.C. oil and gas development companies, or their competitors, and
14 rough projections of future development in the sector.

15 The Low Scenario was comprised of: (a) the Reference Forecast increased by 1 MW to
16 reflect one or two small projects based on recent land tenure sales; and (b) potential load
17 from six projects, each smaller than 5 MW, estimated by oil and gas developers from
18 potential projects.

19 Similarly, the Mid Scenario was comprised of: (a) the Reference Forecast increased by
20 approximately 6 MW, to reflect one large generic project; and (b) potential load from a few
21 large projects, each greater than 5 MW, estimated by oil and gas developers from potential
22 projects.

23 The High Scenario was a compilation of the Reference Forecast, plus the incremental loads
24 described above for the Low and Mid Scenarios.

25 Subsequent to the preparation of this Reference Forecast and growth Scenarios, two
26 significant customer-related events have occurred:

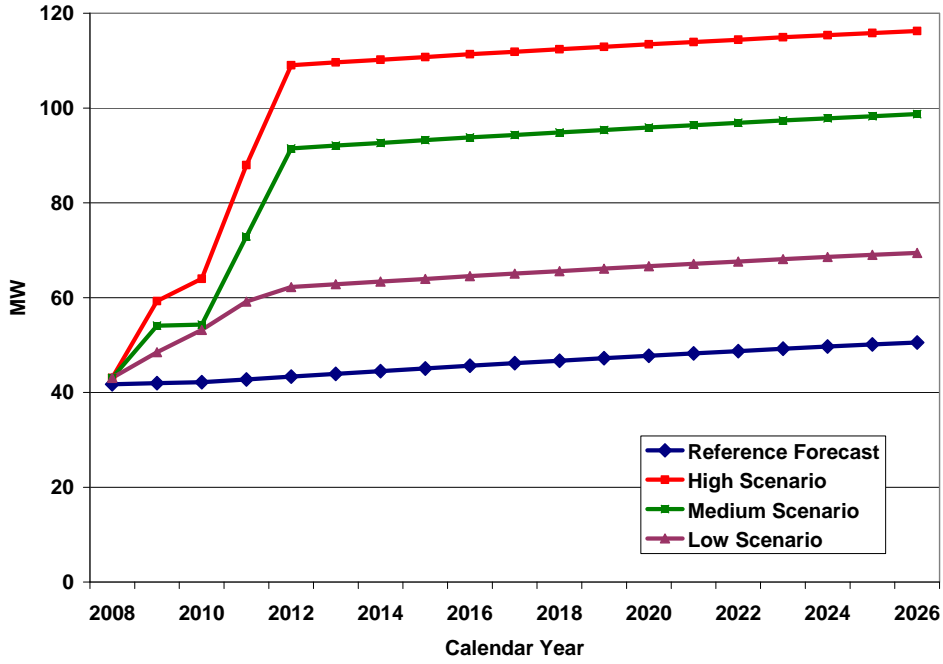
¹⁰ BC Hydro's 2007 Load Forecast is presented in Chapter 2 of the 2008 LTAP (Exhibit B-1), with the full BC Hydro 2007 Load Forecast provided in the 2008 LTAP Appendix D (Exhibit B-1-1). The Fort Nelson load forecast is provided in Tables 9.2 and 9.3 of the BC Hydro 2007 Load Forecast.

- 1 • The two Canfor mill indefinite closures were announced. One or both mills may come
2 back to service some time in the future, depending on market conditions and Canfor's
3 future decisions.
- 4 • BC Hydro obtained interruptible service from the AESO to serve Harvest Energy's
5 requested 10 MW of new service. There is not currently sufficient supply to meet this
6 additional load so it is being served by BC Hydro through an AESO interim tariff approved
7 by the AUC that provides for BC Hydro to pay (on an interim refundable basis) 50 per
8 cent of any incremental TMR cost that may be incurred in serving this load. In addition
9 the Harvest Energy load is curtailable in accordance with AESO operating procedures.
10 As of October 24, 2008, the load has been curtailed ten times in 2008.

11 The following Figure 5-1 and Figure 5-2 present the load forecast scenarios. The Figures
12 that are based on annual capacity or annual peak demand in the FN RP/LTAP are
13 presented in calendar year terms, associated with an assumed December winter peak
14 demand (the fiscal year peak for any one year is assumed to be the calendar year peak for
15 the previous year, for example F2010 peak demand is assumed equal to the 2009 calendar
16 year peak). The energy Figures are presented in fiscal years, linking back to the BC Hydro
17 Load Forecast.

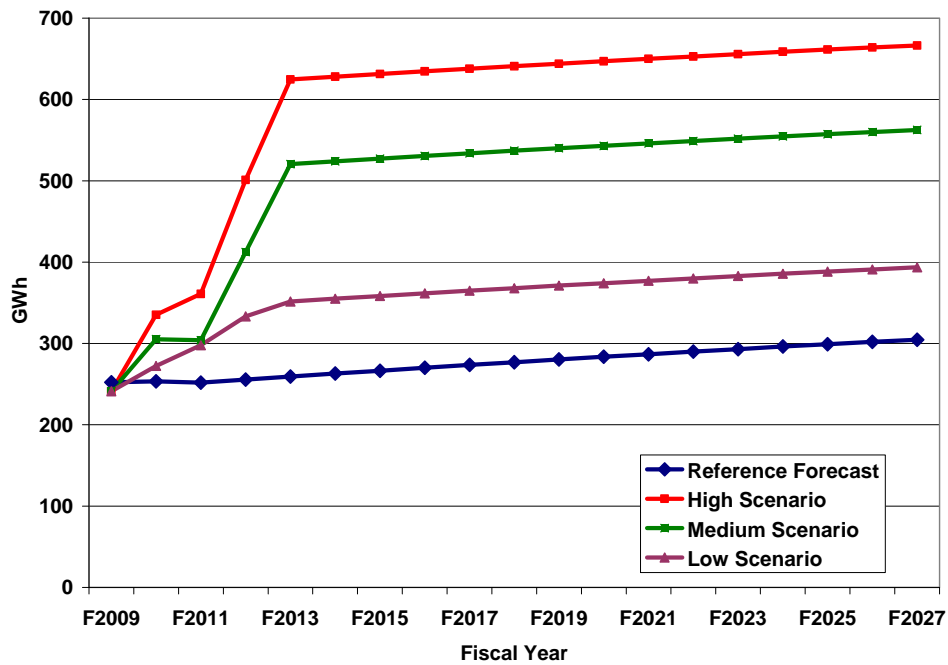
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Figure 5-1 Fort Nelson Region Peak Demand Forecast (before DSM)



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Figure 5-2 Fort Nelson Region Annual Energy Demand Forecast (before DSM)



1 **5.2 Monthly Load Shapes**

2 The monthly heavy load hour (**HLH**) and light load hour (**LLH**) forecasts have been
3 developed for the Reference Forecast and the three Scenarios. These load shapes, set out
4 in section 11, are used in the economic analysis.

5 **5.3 Possible new load in the region**

6 Subsequent to completing the portfolio analysis, BC Hydro received a request for 8 MW that
7 is not in the Reference forecast or in the Scenarios.

8 BC Hydro has also received indications of additional new loads in the Fort Nelson region.
9 This includes possible new loads in the vicinity of Fort Nelson such as possible
10 developments in the Horn River basin some 70 km north of Fort Nelson. These possible new
11 loads could add 100 MW or more to the Scenarios. A map depicting the location of the Horn
12 River basin is attached as Attachment 1 to this Appendix N1.

13 Given the new load is associated with the development of new natural gas supply, it is
14 uncertain at this time how much of the load would be served by BC Hydro. Parties
15 developing the gas resources may choose to use gas drives or install their own
16 self-generation facilities to meet some or all of their electricity requirements.

17 As a result of having load that must be served on an interruptible basis, the number of
18 inquiries for new load received recently, requests for interconnection studies and public
19 announcements on proposed oil and gas developments, BC Hydro believes the Low
20 Scenario to be the prudent minimum load growth profile on which to commit to provide
21 incremental supply capacity and energy notwithstanding the lack of firm commitments for the
22 potential new load.

23 The economic analysis does not include the impact of these possible new loads, but they
24 are treated subjectively in the risk analysis section. Nor have the Scenarios been modified,
25 rather BC Hydro is placing little weight on the 2007 Reference Forecast.

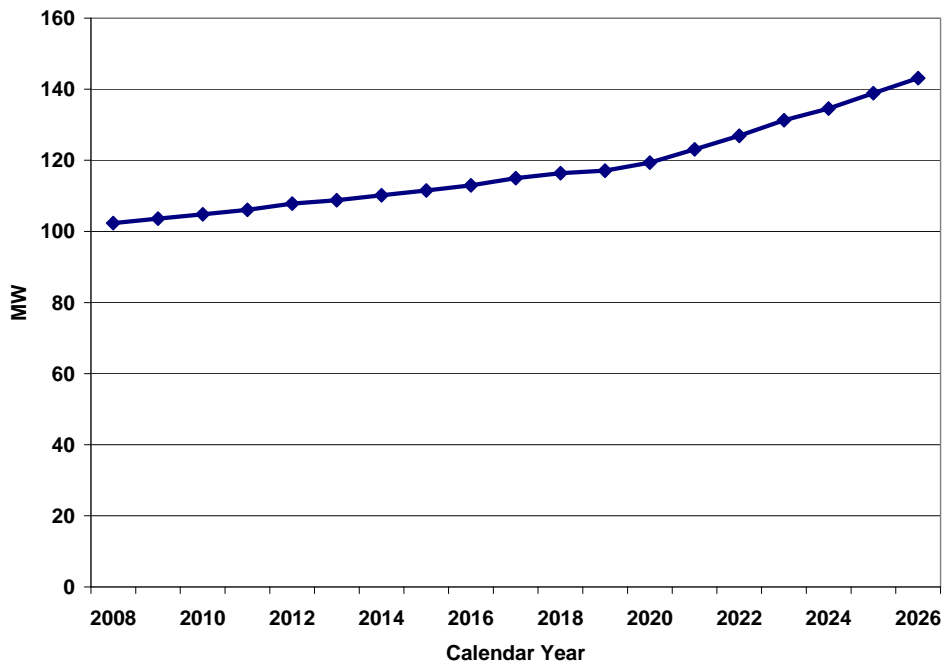
1 **5.4 Load Forecast for the FN/RB region**

2 Availability of electricity to BC Hydro from Alberta at any point in time will depend on the
 3 transmission capacity that is available from central Alberta to the FN/RB region and the
 4 combined load in that region.

5 **5.4.1 Rainbow Lake Region (Alberta side of FN/RB region)**

6 Figure 5-3 presents the forecast of the annual peak demand in the Rainbow Lake area.¹¹

7 **Figure 5-3 Alberta Peak Demand Forecast for the**
 8 **Rainbow Lake Region**



9 **5.4.2 Demand Side Management (DSM) in Fort Nelson region**

10 BC Hydro has completed a localized forecast of the expected DSM savings that would be
 11 realized from the implementation of the DSM Option A that is being analyzed in the 2008
 12 LTAP. Details of the DSM Plan are provided in the 2008 LTAP (Exhibit B-1). Expected
 13 electricity savings in the Fort Nelson region for the Reference Forecast by 2020 is 5.5 MW of

¹¹ The forecast was received from the AESO on April 15, 2008. The load forecast is for the loads at the Alberta substations 747S, 748S, 779S, 791S, 795S, 797S, 828S, 850S, 786S, 832S, 890S.

1 demand and 37.9 GWh/year of energy. No specific cost has been calculated for the Fort
2 Nelson region, but the overall DSM Option A portfolio of programs in the 2008 LTAP is
3 shown to be one of the lowest cost options available to BC Hydro.

4 Given the DSM savings are significantly smaller than the load/resource gap to be filled and
5 are available at a much lower cost than any of the supply options, BC Hydro has completed
6 all of the portfolio analysis assuming the estimated DSM savings are acquired, as forecast.

7 Any specific requests with respect to this DSM are part of BC Hydro's DSM Plan that is
8 addressed in the 2008 LTAP.

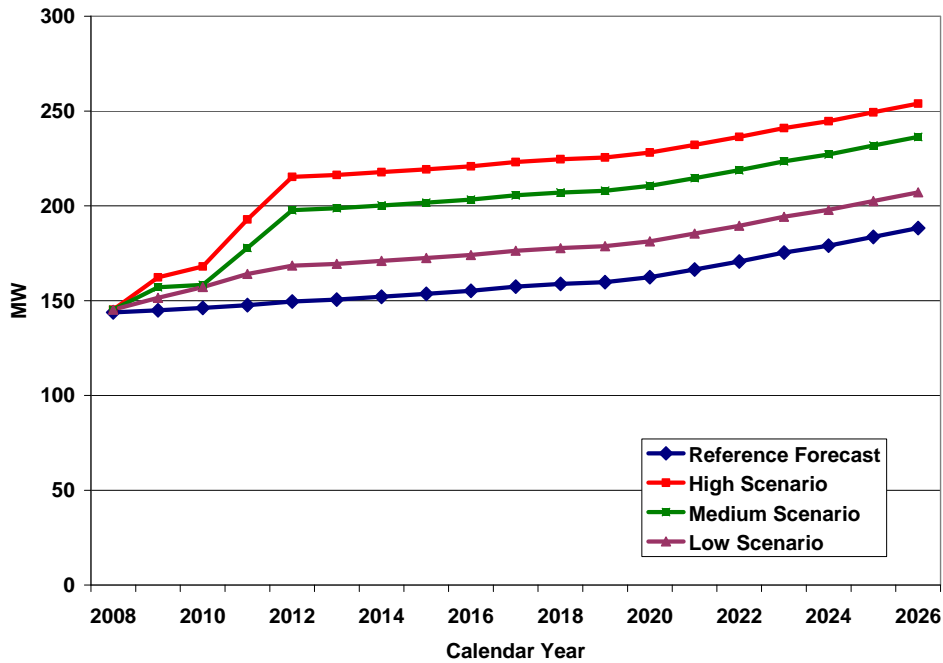
9 It is assumed that any additional DSM that may be available if the projects underlying the
10 new loads in the Low, Mid and High Scenarios do materialize will be incorporated in the
11 design and implementation of those projects. This means that the load Scenarios are
12 effectively net of DSM potential.

13 **5.4.3 FN/RB Load Scenarios net of DSM**

14 Figure 5-4 presents the forecast peak demand for the combined region. In this Figure, the
15 BC Hydro load is net of the DSM associated with the BC Hydro Reference Forecast.

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Figure 5-4 Peak Load in Fort Nelson / Rainbow Lake Region



3 **5.5 Existing and committed resources**

4 **5.5.1 B.C. generation**

5 BC Hydro owns and operates FNG. It is a natural gas-fired facility located 16 km south of
 6 the town of Fort Nelson. The current power plant is configured as a simple cycle gas turbine
 7 (**SCGT**) with an Alstom generator directly coupled to a General Electric (**GE**) LM 6000 gas
 8 turbine. The gas turbine's nominal rated capacity for normal operation is 47 MW in the winter
 9 and 40 MW in the summer.¹²

10 With an average forced outage rate (**FOR**) of 1.39 per cent over the last six years, the plant
 11 has been very reliable and BC Hydro is not expecting any material change in its reliability.¹³

12 The operating experience for each year is provided in Table 5-1.

¹² Modelling of the FNG is 47.8 MW in the winter and 39.5 MW in the summer.

¹³ The FOR = Forced Outage Hours / (Annual Hours – Planned Outage Hours) = 114/(8760 – 597)

1 **Table 5-1 FNG Outage Experience**

| | | | | | | | |
|----------------|-------|-------|-------|-------|-------|-------|---------|
| Hours per Year | F2003 | F2004 | F2005 | F2006 | F2007 | F2008 | Average |
| Planned Outage | 1365 | 960 | 382 | 238 | 312 | 326 | 597 |
| Forced Outage | 101 | 81 | 235 | 123 | 62 | 79 | 114 |
| Total | 1466 | 1042 | 617 | 361 | 374 | 405 | 711 |

2 **5.5.2 Contract Sales**

3 When FNG is running, any excess production to the needs in the local BC Hydro service
 4 area is exported to Alberta. This includes energy sales and sales of the reliability-based
 5 service TMR. Powerex is responsible for these market price-based sales arrangements.

6 **5.5.3 Transmission from Rainbow Lake to Fort Nelson**

7 There is a single circuit 144 kV transmission line (named 1L359 on the B.C. side of the
 8 border) connecting Fort Nelson to Rainbow Lake. Its reliability data for the ten-year period
 9 January 1997 to December 2006 is provided in Table 5-2. The physical transfer limit of the
 10 line from Rainbow Lake to Fort Nelson is assumed to be 117 MW.

11 **Table 5-2 Outage Experience of 1L359**

| Circuit | Total Transient Forced Outages | Transient Forced Outages Freq. Per year | Sustained outage | | | |
|---------|--------------------------------|---|------------------|--------------------|----------------------|---------------------------|
| | | | Total Outages | Frequency Per Year | Average (hours/year) | Unavailability (per cent) |
| 1L359 | 1 | 0.10 | 10.00000 | 1.00000 | 23.03833 | 0.26300 |

12 **5.5.4 Alberta Committed Transmission Capacity to the FN/RB Region**

13 At present, the combined transmission capacity into the region is capable of meeting
 14 130 MW of FN/RB area load. However, to sustain this level of transmission capacity, an
 15 equivalent amount of generation must be providing TMR in the region to meet the under

1 voltage security requirements.¹⁴ This results in effectively no net import to the FN/RB region
2 under normal conditions, notwithstanding the identified transmission capacity.¹⁵

3 Any load served above 130 MW is currently being served on a curtailable basis.

4 The AESO received approval from the AUC in August 2006 to upgrade transmission into the
5 Alberta north-west (called Northwest Alberta Area Upgrade project), the region that feeds
6 the FN/RB region. The approved upgrades will increase the overall capability to meet area
7 load to 145 MW in 2011 without the need for any TMR operation. The base case for
8 Alberta-based transmission in the 2008 FN RP/LTAP is the existing and committed
9 transmission system is called **AESO A0** and reflects the above-documented current and
10 committed transmission capacity.

11 Given the forecast load growth on the Alberta side of the FN/RB region, the physical supply
12 capability at the B.C./Alberta border to support Fort Nelson load supplied by BC Hydro is
13 expected to be as shown in Table 5-3.

14 The TMR requirement to be provided by FNG and Rainbow Lake generation is expected to
15 decline between now and 2011 as the approved and committed new reactive support is
16 added to the Alberta system.

17 **5.5.5 Contract purchases**

18 The FDS is a unique rate provided to BC Hydro, but is based on the same principles as the
19 AESO's transmission capacity service (DTS) to customers interconnected to the high
20 voltage network in Alberta.

21 The current FDS capability to 28.5 MW has a five -year termination notice and is assumed to
22 be available to BC Hydro in the long term. The additional 10 MW curtailable capacity is also
23 assumed to be available in the long term based on the same termination provisions, with the
24 difference being that it is being supplied on an interim tariff.

¹⁴ Other generation in the FN/RB region includes five units in Rainbow Lake, however, only three units are operational.

¹⁵ The transmission capacity is, in effect, operational contingency reserve available for N-1 support.

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**Table 5-3 Transmission Capability available to
BC Hydro**

| Year | 2008 | 2009 | 2010 | 2011 ¹⁶ |
|---------------------|------|--|------|--------------------|
| Firm (no TMR) | 0.0 | Gradually increasing to 28.5 ¹⁷ | | 39 |
| Firm (with TMR) | 28.5 | 28.5 | 28.5 | 74 |
| Curtable | 10.0 | 10.0 | 10.0 | - |
| Total with Curtable | 38.5 | 38.5 | 38.5 | 74 |

3 **5.6 The current and committed load/resource balance**

4 The following planning load/resource balance analysis is based on peak demand only. As
5 long as the peak demand is forecast to be reliably met, there is no expectation of an energy
6 reliability shortfall.

7 Figure 5-5 presents the load/resource balance before considering reliability and the need for
8 reserves in the region to meet the Partial N-1 reliability measure.

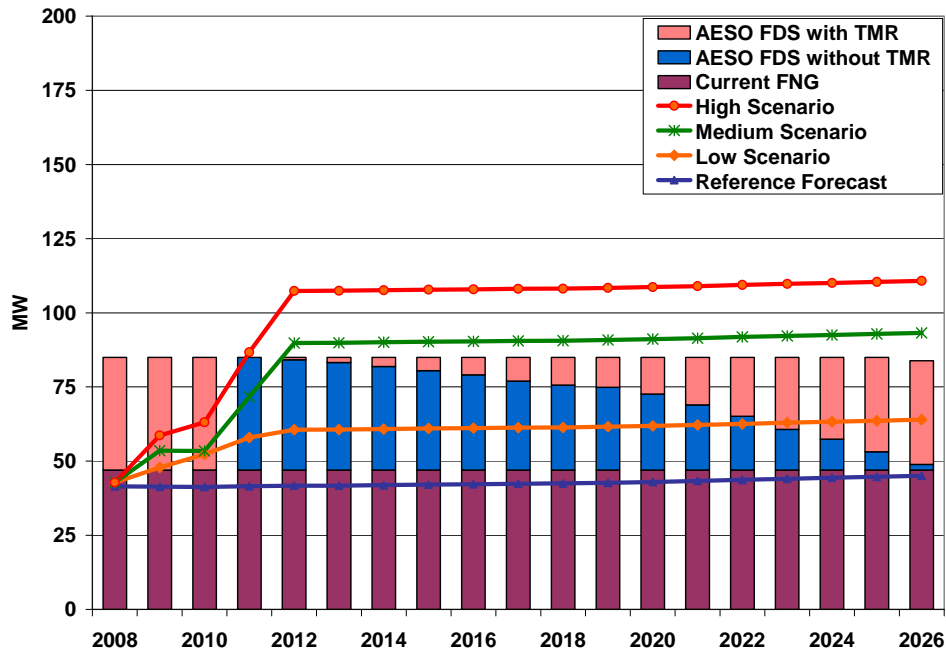
9 BC Hydro is assuming that the committed 38.5 MW (28.5 MW firm plus 10 MW curtable)
10 from Alberta will become firm by 2011 and will continue to be available to BC Hydro. The
11 amount expected to be available is presented in Figure 5-5 and, as indicated, would require
12 varying levels of TMR support through time as a result of load growth in the Rainbow lake
13 region.

¹⁶ The current physical requirement for curtable load should be alleviated by 2011.

¹⁷ As AESO A0 is implemented.

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Figure 5-5 Peak Load/Resource Balance before considering Reserve Requirements



3 As described in section 3.1, there must be resources available that are sufficient to supply
 4 the customer demand even when the largest single resource is out of service (the largest
 5 single contingency; N-1 criteria). FNG is currently the largest single contingency in the FN
 6 region.

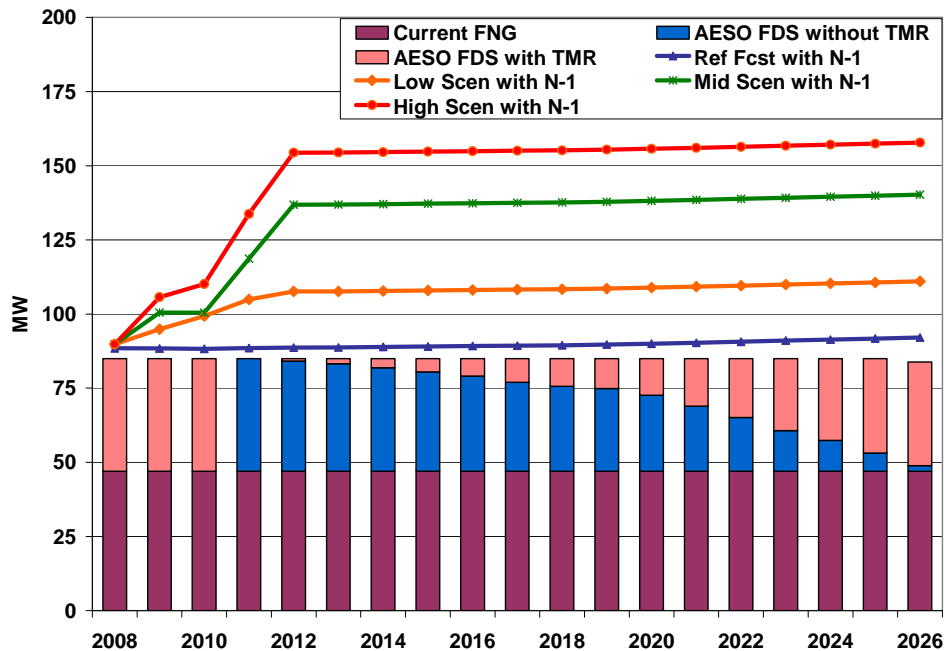
7 The N-1 Load/Resource Balances presented in the 2008 FN RP/LTAP (first shown in
 8 Figure 5-6) are based on the N-1 measure. In that respect, the load/resource balances
 9 compare (1) the full supply capability, putting all supply resources in the supply stack,
 10 against (2) the largest single local generating facility considered the contingency in any year
 11 being analyzed added to the annual peak demand for that year for the Reference Forecast
 12 and Scenarios.

13 In this representation, the capacity of FNG has been added to the Reference Forecast and
 14 Scenarios in all years to reflect the N-1 condition. The gap to the supply (also including the
 15 FNG) represents the shortfall in meeting the N-1 reliability measure.

1 As presented in Figure 5-6, there is insufficient capacity currently available to reliably meet
 2 the customer demand. The Load/Resource Balance for 2008 shows there is a shortfall in
 3 supply of approximately 5 to 10 MW even if none of the new load growth considered in the
 4 Scenarios becomes a reality.¹⁸

5 The Reference Forecast and the Scenarios do not assume any reduction in load in Fort
 6 Nelson resulting from the indefinite closure of the Canfor mills. Each mill has a requirement
 7 of approximately 6 to 8 MW.

8 **Figure 5-6 Peak Load/Resource Balance including**
 9 **N-1 Reserve Requirements¹⁹**



10 **5.7 Electricity Market Prices**

11 The 2008 FN RP/LTAP uses BC Hydro's Electricity Price Forecast as an input. This is the
 12 same electricity price forecast that is used in, and presented in Chapter 4, of the 2008

¹⁸ The AESO's current 10 MW curtailable load requirement described in section 2.2 is as a result of this N-1 reliability shortfall.

¹⁹ The load/resource balances including reserve requirements add the largest single contingency at any one time period to the load scenario. All supply sources are represented as being available. Any gap (load with N-1) being above the supply) represents a shortfall in ability to meet an N-1 reliability condition.

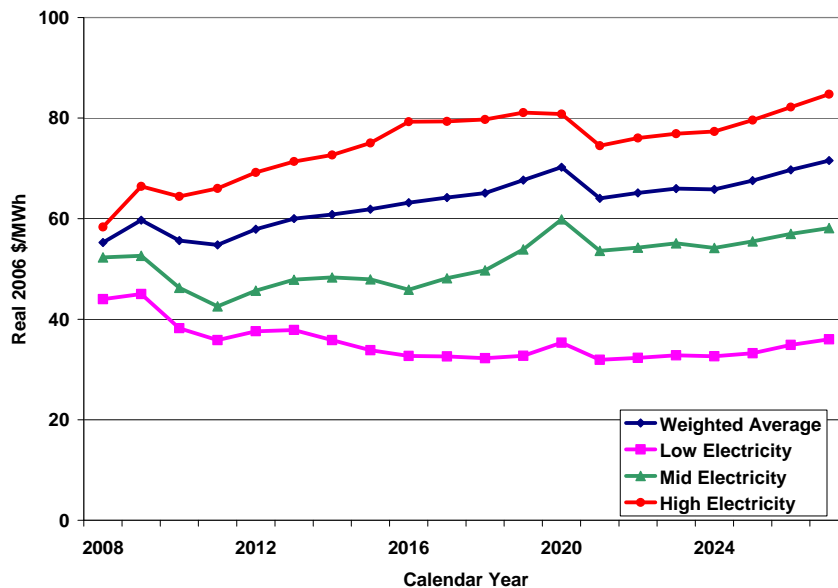
1 LTAP. As identified in Chapter 4 of the 2008 LTAP, the expected impact of GHG offset costs
 2 are reflected in the forecasts of electricity market prices based on the Linked Markets
 3 forecast of GHG offset costs.

4 **5.7.1 B.C. Lower Mainland Price**

5 Figure 5-7 presents BC Hydro's Electricity Price Forecast in 2006 dollars for the BC Hydro
 6 Lower Mainland (B.C. Border) price. This is the electricity market price that would apply in
 7 the portfolios where a BCTC transmission line is assumed to connect Fort Nelson to the
 8 Peace River region.

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Figure 5-7 BC Hydro 2008 Forecast of Electricity Prices in the B.C. Lower Mainland



11 **5.7.2 Alberta AESO Market Price**

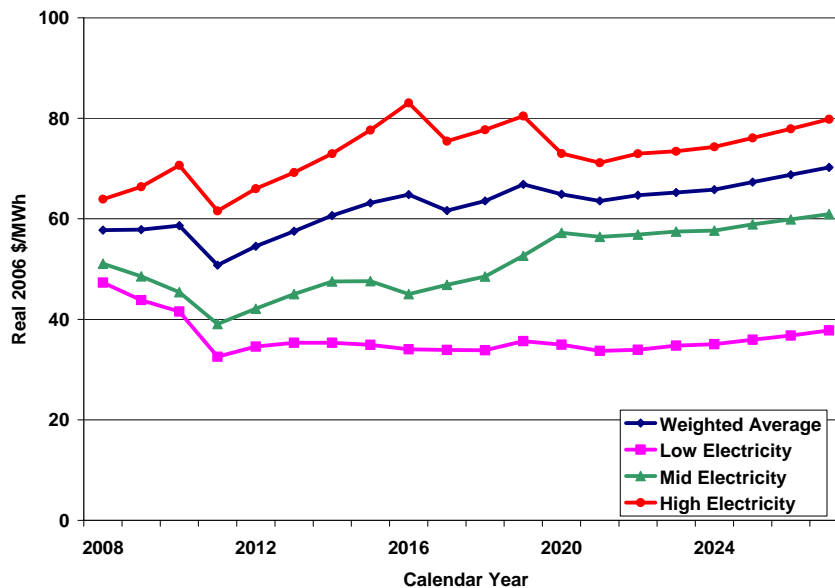
12 Figure 5-8 presents BC Hydro's January 2008 Electricity Price Forecast in 2006 dollars for
 13 the Alberta electricity market (AESO market price). It is the price forecast used to calculate
 14 energy purchase costs for energy purchased from Alberta.

15 As identified in section 4.4.2 of the 2008 LTAP, the electricity market prices include some
 16 allowance for the expectation of GHG offset requirements in the Western Electric

1 Coordinating Council (**WECC**). The forecast market prices for Alberta are based on the
 2 simulations of the WECC, as measured at the Alberta AESO node.

3 With respect to Alberta, the assumption was that offsets would be required for GHG
 4 emissions above 600 tonnes of CO₂e/GWh.²⁰ Therefore, the costs for GHG offsets above
 5 the 600 tonnes of CO₂e/GWh level are assumed to be priced into AESO electricity market
 6 price in the analysis in the FN RP/LTAP. Risk analysis regarding the possible requirement to
 7 offset GHG associated with imports is set out in section 7.5.2.4.2.

8 **Figure 5-8 BC Hydro 2008 Forecast of Electricity**
 9 **Prices in the AESO Market**



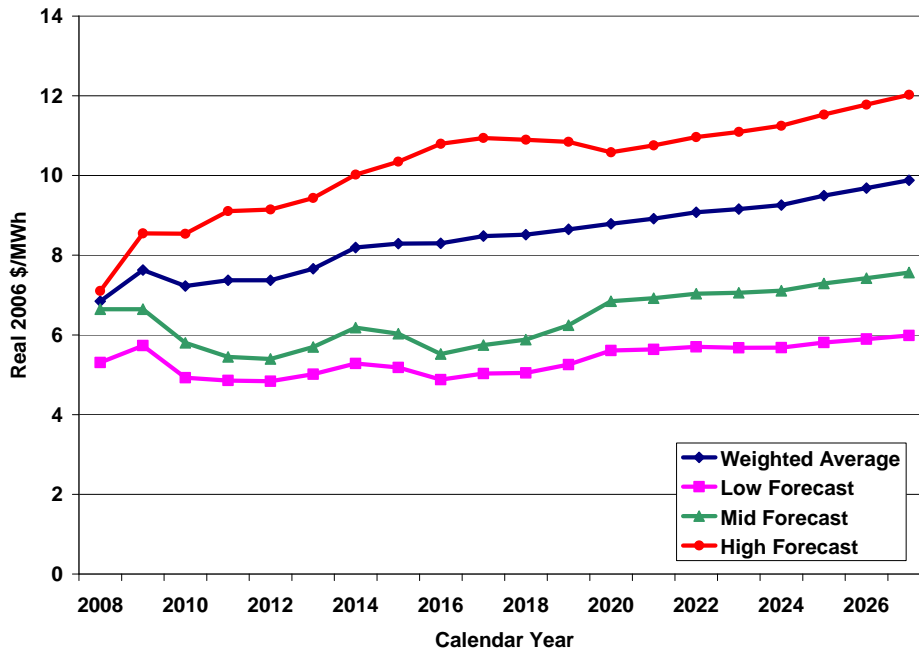
10 **5.8 Natural Gas Prices**

11 Figure 5-9 presents the BC Hydro forecast natural gas prices underlying the BC Hydro
 12 2008 Electricity Price Forecast. This gas price forecast is the same forecast as used in
 13 Chapter 4 of the 2008 LTAP.

²⁰ Exhibit B-1, page 4-20, lines 14-21.

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Figure 5-9 BC Hydro 2008 Forecast of Natural Gas Prices for Station 2



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4 Gas transportation from the Station 2 hub is estimated to be a credit (negative cost) of
5 \$0.10/GJ on capacity and 0.75 per cent fuel (energy).

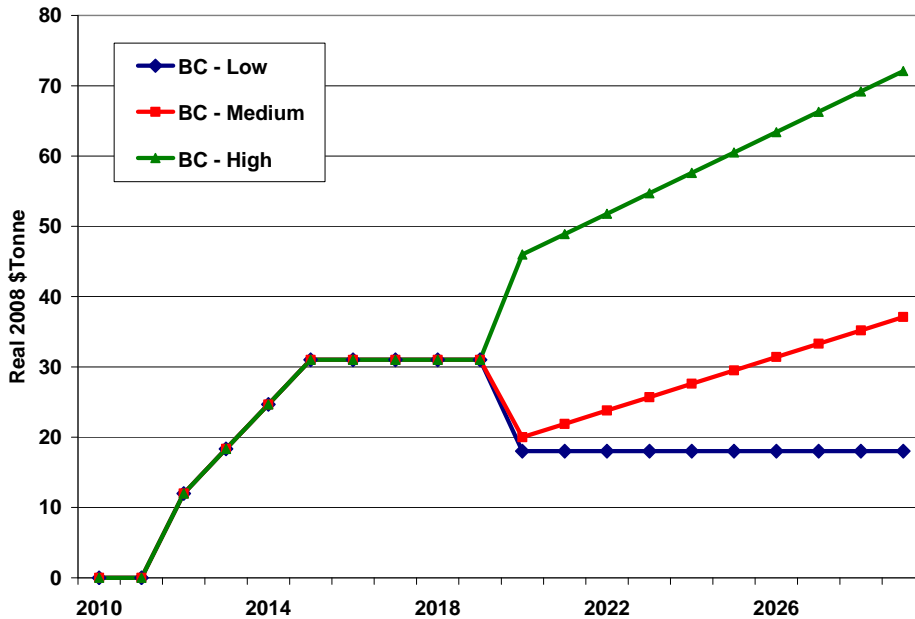
6 As described in Chapter 4 of the 2008 LTAP, the B.C. Government's February 2008 Budget
7 declared that there would be a carbon tax added to natural gas starting in July 2008 at
8 \$0.50/GJ and increasing annually to \$1.50/GJ in 2012. This additional cost is included in the
9 analysis as a separate operating cost and not included in the commodity cost forecast
10 presented in Figure 5-9. Subsequent to the original filing of the 2008 LTAP, the B.C.
11 Government introduced and passed the *Climate Tax Act* and released the Climate Change
12 Action Plan. The Climate Action Plan in particular makes it more certain that either the
13 carbon tax or the GHG offset costs, but not both at one time, would apply to a generating
14 facility.

15 As a result, BC Hydro updated its original assumption regarding the application of the B.C.
16 carbon tax by removing the carbon tax in situations where the GHG offset requirement
17 would apply. This is further described in the response to BCUC IR 1.94.1 (Exhibit B-3).

1 **5.9 Greenhouse Gas Cost Forecasts**

2 The GHG cost forecast is the forecast developed by Natsource and presented in Chapter 4
 3 of the 2008 LTAP.

4 **Figure 5-10 Forecast of GHG Offset Costs**



5 **6 Planning Horizon Resource Options**

6 **6.1 Upgrade existing SCGT (FNU2 or FNU3)**

7 BC Hydro identified two alternative Resource Smart projects to upgrade the existing FNG
 8 SCGT to be a CCGT. Both alternatives involve upgrading the existing gas turbine,
 9 upgrading or replacing the current heat recovery boiler to a once through steam generator
 10 (**OTSG**) and installing a new steam-driven turbine-generator set. The primary distinction
 11 between the two alternatives is that FNGU Case 2 (**FNU2**) does not include duct firing²¹
 12 while FNGU Case 3.2 (**FNU3**) does. FNU2 would provide approximately 10 MW of capacity
 13 from substantially the same amount of natural gas as is currently used at FNG. FNU3

²¹ Duct firing is described at Exhibit B-1-7, page 3, footnote 3.

1 provides approximately 26 MW of capacity, and would require additional natural gas for the
 2 capacity increment above FNU2.

3 Assumptions with respect to FNU2 and FNU3 for the analysis are provided in Table 6-1. The
 4 capital cost used in the economic analysis is presented in 2012 dollars and includes project
 5 reserve and interest during construction (**IDC**). Consistent with past practice and BCUC
 6 determinations,²² the economic analysis of FNU2 and FNU3 is based on incremental costs
 7 excluding corporate overhead.

8 **Table 6-1 FNG Upgrades FNU2 and FNU3²³**

| Plant Factors | | FNU2 | FNU3 | | |
|-------------------------|---------------|---------------------|---------------------|----------|---|
| Incremental Capacity | MW | 10 | 26 | | Winter Rating |
| Capital Costs | \$M | 86.3 | 129.1 | Fixed | Direct cost in 2012 dollars, including project reserve but excluding allocated corporate overhead. Cost estimate is + 35%/- 15% |
| Fixed O&M | \$/MW-Mo | 6,100 | 6,100 | Infl Adj | Staff, Fixed Maintenance, LTSA ²⁴ , Grants in lieu, etc |
| Fixed O&M | \$/K/Mo | 336 | 336 | Infl Adj | Dollar Cost of Fixed O&M |
| Power Variable O&M | \$/MWh | 1.10 | 1.10 | Infl Adj | Covers water treatment and other variable maintenance |
| Operations Variable O&M | \$/Fired Hour | 150 | 150 | Infl Adj | LTSA charges and own-forces O&M |
| Earliest Availability | | Dec 2011 (for 2012) | Dec 2011 (for 2012) | | Subject to planning, regulatory, financing and development risks |

9 **6.2 New 56 MW CCGT in Fort Nelson**

10 Two alternatives that would exist for a new CCGT in Fort Nelson would be to upgrade FNG
 11 with a second CCGT of similar characteristics as the FNU2 or the FNU3 projects on the
 12 same site, or to develop a new greenfield CCGT project of similar size. The characteristics

²² BCUC Decision Order C-8-07 (Revelstoke Unit 5 CPCN), page 59.

²³ Costs are in 2008 dollars except as noted.

²⁴ Long Term Service Agreement (**LTSA**)

1 for either alternative are assumed to be the same for the analysis in the 2008 FN RP and
2 are presented in Table 6-2.

3 A second CCGT could add approximately 55 to 75 MW of capacity. However, a new CCGT
4 is not an alternative to FNGU because a new CCGT would not be able to meet an ISD of
5 2012. The earliest ISD for installing a second CCGT in the Fort Nelson area depends on
6 whether:

- 7 • the second CCGT is a Resource Smart project sited at BC Hydro's FNG site (named the
8 Fort Nelson Expansion Project); or
- 9 • the second CCGT is a new, greenfield development.

10 BC Hydro has, for purposes of estimating the ISD for the two CCGT scenarios, assumed a
11 two to three-year period for the engineering, procurement and construction.

12 In the analysis, the new CCGT, called **C57**, is set to be the same size and performance
13 characteristics as the FNU2.

14 The assumed C57 costs are summarized in Table 6-2 and are based on data from the
15 recently completed Resource Options Update that forms part of BC Hydro's 2008 LTAP
16 filing.²⁵ The cost may not reflect current market or local conditions, and is more uncertain
17 than the cost estimates for FNU2 or FNU3.

²⁵ The Resource Options Update is contained in Appendix F1 of the 2008 LTAP.

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Table 6-2 New CCGT (C57) in Fort Nelson or at FNG²⁶

| Plant Factors | Units | C57 | | |
|-------------------------|---------------|------------|----------|---|
| Incremental Capacity | MW | 56 | | Winter Rating |
| Capital Costs | \$M | 174.2 | Fixed | Direct cost in 2012 dollars, excluding allocated corporate overhead |
| Fixed O&M | \$/MW-Mo | 5,333 | Infl Adj | Staff, Fixed Maintenance, LTSA, Grants in lieu, etc |
| Fixed O&M | \$/K/Mo | 293 | Infl Adj | Dollar Cost of Fixed O&M |
| Power Variable O&M | \$/MWh | 3.40 | Infl Adj | Covers water treatment and other variable maintenance |
| Operations Variable O&M | \$/Fired Hour | 150 | Infl Adj | Covers LTSA charges and own-forces O&M |
| Earliest availability | | for 2014 | | subject to planning, regulatory, financing and development risks |

3 **6.2.1 Fort Nelson Expansion Project**

4 FNG has property available, and was originally designed, to be increased in size. Most of
5 the infrastructure exists to double the size of the project, or possibly more.

6 BC Hydro has initiated an Identification phase study for the Fort Nelson Expansion Project.
7 The study is to develop a plant design and cost estimate to an accuracy range of +65/-35%.
8 The study will look at several new generating size options, including duplicating the FNGU,
9 whether as FNU2 or FNU3. The study is expected to be completed in the first quarter of
10 2009.

11 If a second CCGT, duplicating the FNU2, were installed at that site, it would provide
12 approximately an additional 56 MW of winter capability. Some of the existing infrastructure
13 has been sized for this second CCGT which would provide some economies of scale
14 relative to a similar new, greenfield CCGT as described in the following section. However, in
15 this analysis the cost of expanding FNG with a second CCGT was assumed to be the same
16 as the cost of a generic new, greenfield CCGT, which is summarized in Table 6-2.

²⁶ Costs are in 2008 dollars except as noted.

1 The earliest ISD for the Fort Nelson Expansion Project is likely late 2013, for the following
2 reasons:

- 3 • Unlike FNGU, the Fort Nelson Expansion Project would trigger the *B.C. Environmental*
4 *Assessment Act (BCEAA)* because pursuant to the Reviewable Projects Regulation it
5 would be a modification to an existing facility resulting in FNG having a rated nameplate
6 capacity that has increased by 50 MW or greater. Pursuant to section 8 of *BCEAA*, no
7 construction could begin on the Fort Nelson Expansion Project until an Environmental
8 Assessment Certificate (**EAC**) had been obtained. BC Hydro estimates that the *BCEAA*
9 process would take approximately 14 months from submission of the project description
10 to the B.C. Environmental Assessment Office to issuance of the EAC. In estimating the
11 length of time of the *BCEAA* process, BC Hydro has taken into account the fact that
12 some of the existing infrastructure could be used; BC Hydro estimates a longer *BCEAA*
13 process for a greenfield CCGT (see below). BC Hydro has also concluded that *Canadian*
14 *Environmental Assessment Act (CEAA)* is likely not triggered for the Fort Nelson
15 Expansion Project; this assumption may not hold for a greenfield CCGT. See below.

- 16 • Similar to FNGU, a determination for Fort Nelson Expansion Project expenditures would
17 be sought from the BCUC pursuant to section 44.2 of the *UCA*. This process could result
18 in a hearing lasting approximately seven months. This process could occur while the
19 *BCEAA* process is occurring as long as BC Hydro had a good estimate of the likely
20 environmental mitigation costs. BC Hydro assumed this to be the case with respect to the
21 Fort Nelson Expansion Project.

22 **6.2.2 New Greenfield CCGT in Fort Nelson**

23 One available option with the necessary capacity reliability is a new greenfield CCGT in the
24 Fort Nelson area. This analysis assumes a nominally rated 50 MW, one on one
25 configuration based on a GE LM 6000 machine, which is a similar CCGT configuration to
26 what the FNG project will be once upgraded. Given local conditions and the similarity to
27 FNG, it is also assumed to be capable of providing 56 MW (winter peak conditions).

28 The earliest ISD for a new greenfield CCGT is likely to be mid to late 2014, for the following
29 reasons:

- 1 • Pursuant to Policy Action No. 13 of the 2002 Energy Plan, this project would not be a
2 Resource Smart project and therefore must be an independent power producer (**IPP**)
3 project. A copy of Policy Action No. 13 is attached as Attachment 2. Accordingly, a power
4 acquisition process – whether a Call for Tenders or a Request for Proposals – would be
5 required. The power acquisition process would likely take approximately 18 months from
6 development through to filing any Electricity Purchase Agreement (**EPA**) awarded to an
7 IPP with the BCUC pursuant to section 71 of the *UCA*. Difficult issues of dispatchability
8 and which party – the IPP or BC Hydro - should bear the natural gas price and GHG risks
9 would need to be addressed both in the EPA and in the section 71 filing.
- 10 • The ISD assumes that BC Hydro would not seek a determination pursuant to section 44.2
11 of the *UCA* for expenditures related to the new greenfield CCGT, prior to the power
12 acquisition process and the section 71 filing. Ministerial Order M202 exempts IPPs selling
13 electricity to BC Hydro from the requirement to obtain a Certificate of Public Convenience
14 and Necessity. However, BC Hydro may wish to reduce regulatory risk and seek a BCUC
15 determination.
- 16 • Again, unlike the FNGU, a new greenfield CCGT would trigger *BCEAA* because, under
17 the Reviewable Projects Regulation, it would be a new facility with a rated nameplate
18 capacity of equal to or greater than 50 MW. In BC Hydro's view, the environmental
19 assessment process for a new greenfield CCGT would be approximately 18 months,
20 longer than for the second CCGT at the FNG site because: (1) there may be location
21 impact issues; and (2) *CEAA* may be triggered. Generally speaking, BC Hydro's
22 experience has been that IPPs are reluctant to advance too far into the *BCEAA* process
23 without an EPA, and that accordingly the *BCEAA* process would likely occur after the
24 section 71 process.

25 **6.3 New 31 MW CCGT in Fort Nelson**

26 In the second round of Information Requests (**IR**) the BCUC requested that BC Hydro
27 include a CCGT of approximately 27.7 MW in its analysis.²⁷ BC Hydro developed an early
28 investigative cost estimate for a 31 MW CCGT (at the FNG site or greenfield site), called
29 **C31** in the analysis.

²⁷ BCUC Information Requests 2.222.2 and 2.222.3 (Exhibit A-5).

1 To respond to the above mentioned IRs, the portfolios that include this C31 do not include
2 either FNU2 or FNU3. Such portfolios would be mutually exclusive to building a second
3 CCGT on the existing site and may create some conflicts with FNU3.

4 BC Hydro estimated the cost for this hypothetical 31 MW CCGT from the estimates included
5 in the Resource Options Update for the generic 50 MW CCGT and adjusted for project size
6 based on industry market literature. As such, the cost estimate may not reflect current
7 market or local conditions, and is more uncertain than the cost estimates for FNU2 or FNU3.

8 Development issues and risks would generally be the same as those identified with respect
9 to the 56 MW CCGT (greenfield or FNG site) with the following exceptions:

- 10 • The C31 project would not trigger *BCEAA*, but may trigger *CEAA* if it is a greenfield site;
- 11 • The cost to arrange water and effluent discharge would need to be added to the project
12 cost; and
- 13 • If such a project were to be sited at FNG as an alternative project to the Fort Nelson
14 Expansion Project, there would be additional time required (later ISD) for development
15 and design; or
- 16 • If the project is developed at a site other than FNG a new site and transmission
17 interconnection infrastructure would be required.

18 The assumed cost for C31 used in the analysis is summarized in Table 6-3.

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Table 6-3 New 31 MW CCGT (C31) in Fort Nelson or at FNG²⁸

| | | | | |
|-------------------------|---------------|----------|----------|---|
| Plant Factors | | C31 | | |
| Incremental Capacity | MW | 31 | | Winter Rating |
| Capital Costs | \$M | 143.2 | Fixed | Direct cost in 2012 dollars, excluding allocated corporate overhead |
| Fixed O&M | \$/MW-Mo | 5,333 | Infl Adj | Staff, Fixed Maintenance, LTSA, Grants in lieu, etc |
| Fixed O&M | \$/K/Mo | 165 | Infl Adj | Dollar Cost of Fixed O&M |
| Power Variable O&M | \$/MWh | 3.40 | Infl Adj | Covers water treatment and other variable maintenance |
| Operations Variable O&M | \$/Fired Hour | 150 | Infl Adj | Covers LTSA charges and own-forces O&M |
| Earliest availability | | for 2014 | | Subject to planning, regulatory, financing and development risks |

3 6.4 Results of Request For Expressions Of Interest (RFEOI) for Clean Resources

4 BC Hydro issued a RFEOI for the provision of clean or green electricity from IPPs in the Fort
 5 Nelson area. The request was issued in July 2007, with a deadline for responding of
 6 September 30, 2007.²⁹ BC Hydro's 2007 RFEOI received a total of sixteen responses (one
 7 response was disregarded as ineligible because it was not clean or green). The
 8 submissions, broken down by project type, were: six bioenergy, two small hydro, six wind,
 9 one geothermal and one pumped storage.

10 Since this was an RFEOI, the submissions did not provide a commitment from the
 11 proponents. As a result, these potential projects can only provide BC Hydro with an
 12 indication of whether it is possible to conduct a successful clean or green electricity call in
 13 the Fort Nelson region.

14 In the Fort Nelson region, BC Hydro requires a reliable source of dependable capacity that
 15 is dispatchable and economically capable to produce energy at relatively high capacity

²⁸ Costs are in 2008 dollars except as noted.

²⁹ The notice of the RFEOI, along with a summary of the responses, is provided in Appendix Q to the 2008 LTAP (Exhibit B-1-1).

1 factor. This reliability is critical at all times, including during LLHs when the region's gas-
2 turbine generators may be dispatched down to minimum MW levels, or even dispatched off.

3 Of the sixteen responses, only the bioenergy projects could potentially provide this level of
4 reliability in supply. The RFEOI results provide some indication that there is a possibility of
5 locating a wood waste biomass generating station in the area, but that it may not be
6 dispatchable, and would be small, have relatively large fuel supply risk particularly with the
7 uncertainty at Canfor, and relatively expensive (between 150 \$/MWh and 175 \$/MWh).

8 It is unlikely that BC Hydro's supply need could be met by clean or renewable resources
9 alone, given the timing and the amount of the potential load growth in the area.

10 In the analysis, a generic 10 MW biomass purchase contract priced at 160 \$/MWh in 2012
11 escalating at 50 per cent of the Consumer Price Index, reflecting approximately 150 \$/MWh
12 levelized cost over the term of the analysis. It is assumed the plant would be available from
13 2012 through to the end of the study period, 2027; and that the plant would not be
14 dispatchable.

15 Other than the above, BC Hydro did not obtain any information of any realistic potential for
16 other clean or renewable supply options available in the Fort Nelson area that would meet
17 BC Hydro's upcoming supply requirements.

18 **6.5 Supply from Alberta**

19 A base assumption in BC Hydro's FN RP/LTAP analysis is that BC Hydro would be able to
20 contract for the purchase of any physical supply that is available from the AESO at the
21 B.C./Alberta border.

22 **6.5.1 Transmission Upgrade Options**

23 The current transmission capacity to the FN/RB region is sufficient to provide BC Hydro with
24 38.5 MW of capacity. At this capacity, TMR is required and firm load may have to be
25 curtailed.

1 As described in section 5.5.4, committed transmission upgrades in Alberta are expected to
 2 increase the possible capacity into the FN/RB region to 145 MW by 2011 absent any need
 3 for TMR or curtailable loads. Additional transmission expansion in the Alberta northwest will
 4 be required if the AESO is to provide additional service to BC Hydro.

5 The AESO has provided BC Hydro with early Investigation phase estimates of costs to
 6 increase the transmission capacity to Rainbow Lake. A fourth alternative considered by the
 7 AESO was rejected and not offered because it was uneconomic relative to the other AESO
 8 alternatives. The three alternatives and transmission capacity levels are as shown in
 9 The AESO's base plan is to have sufficient transmission capacity to meet a region's
 10 requirements without requiring TMR operation. However, BC Hydro understands that there
 11 would be some additional capacity that would be available with TMR operation, assumed to
 12 be 35 MW in each case.

13 Table 6-4

14 For the analysis in the 2008 FN RP, BC Hydro has included the full annual levelized cost of
 15 any incremental transmission that is included in the portfolio analysis. A levelized cost in
 16 millions of dollars per year was calculated for each incremental transmission option based
 17 on a book life of 40 years and an 8 per cent nominal discount rate.

18 The AESO's base plan is to have sufficient transmission capacity to meet a region's
 19 requirements without requiring TMR operation. However, BC Hydro understands that there
 20 would be some additional capacity that would be available with TMR operation, assumed to
 21 be 35 MW in each case.

22 **Table 6-4 Transmission Upgrades in Alberta**

| Description | In-service Date | Capacity w/o TMR (MW) | Marginal Losses (%) | Capital Cost ³⁰ (\$M) | Levelized Cost ³¹ (\$M/year) |
|---|-----------------|-----------------------|---------------------|----------------------------------|---|
| AESO A1. Convert the new Wesley Creek to Hotchkiss double circuit line to 240 kV operation | 2011 | 170 | 36% | 35 | 2.9 |

³⁰ Costs were reported to be in 2008 dollars with a +/- 50 per cent capital cost band of uncertainty.

³¹ Nominal dollars.

| | | | | | |
|---|------|-----|-----|-----|------|
| AESO A2. A1 plus extend 144kV single circuit Hotchkiss to Rainbow Lake (230km) | 2013 | 200 | 38% | 155 | 13.0 |
| AESO A4. A1 plus extend new double circuit line to Rainbow Lake | 2013 | 350 | 37% | 330 | 33.8 |

1 BC Hydro expects that AESO A1 will be developed either by the AESO based in internal
 2 requirements or as a result of BC Hydro's request for additional capacity that has been
 3 initiated by the Preliminary Assessment Application described in section 7.3. If the AESO
 4 proceeds with this project, the increase in capacity could be available for 2011.

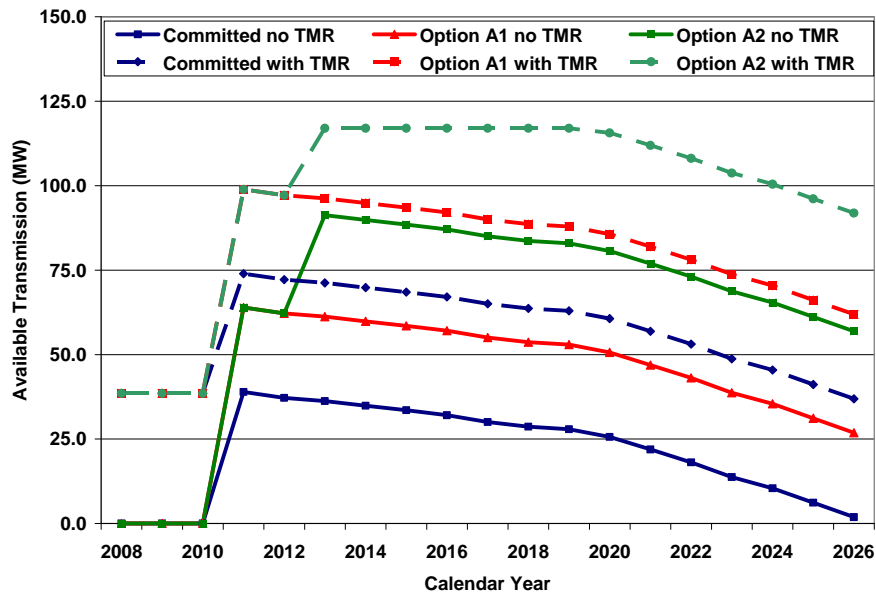
5 This transmission expansion project is required if the AESO is to provide additional service
 6 to BC Hydro. Once upgraded, BC Hydro expects there to be approximately 64 MW in 2011
 7 and 62 MW in 2012 available at the interconnection without requiring TMR. This capacity
 8 level declines as load grows in the Rainbow Lake region of Alberta.

9 BC Hydro considers AESO A2 will have increased development risk relative to AESO A1
 10 because it includes the construction of a new 230 km 144 kV transmission line. The AESO
 11 A2 would face more public and regulatory scrutiny relative to AESO A1 as the latter requires
 12 very little new infrastructure, no new transmission towers or line and a much lower cost.

13 Transmission capacity assumed to be available to BC Hydro at the B.C./Alberta border is as
 14 shown in Figure 6-1 for AESO A0, A1 and A2. As stated in section 5.5.3, the maximum
 15 transfer of the line from Rainbow Lake to Fort Nelson is assumed to be 117 MW.

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Figure 6-1 Available Transmission at B.C./ Alberta Border for AESO Transmission Options



3 The above transmission upgrade options may include some additional reactive support in
4 the FN/RB region, some of which may be best located in Fort Nelson.

5 As shown in Figure 6-1, AESO A2 with TMR would be sufficient to utilize all capacity on the
6 existing circuit from Rainbow Lake to Fort Nelson, at least to a Partial N-1 reliability
7 measure. AESO A4 would add 150 MW of capacity relative to AESO A2 at an added cost of
8 \$175 million. Such an increment to capacity would require a second circuit from Rainbow to
9 Fort Nelson if the capacity were to be relied on to meet the load in Fort Nelson. No
10 additional analysis is included with respect to option AESO A4.

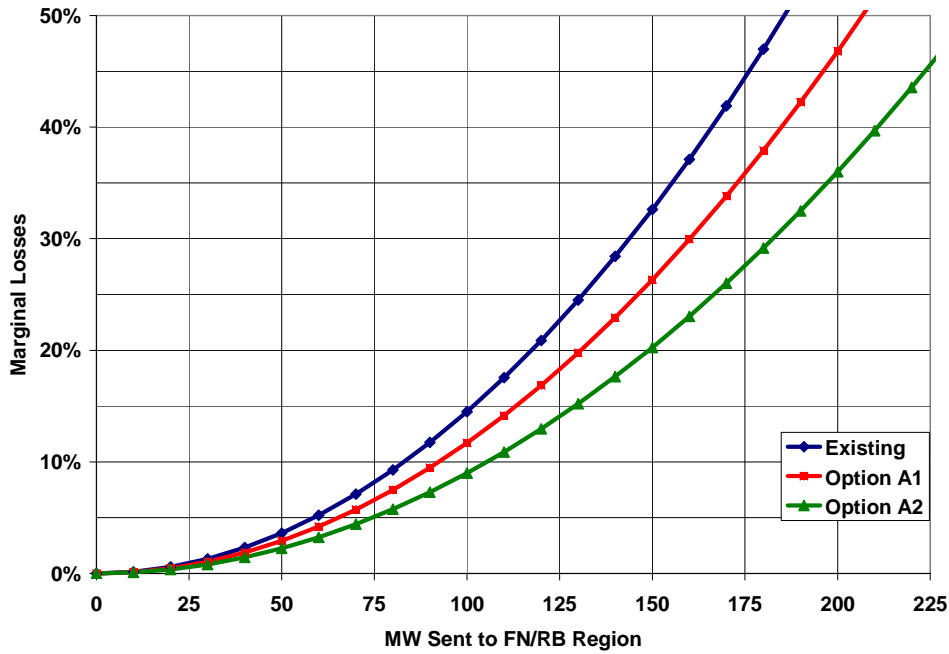
11 Additional transmission and area supply studies will have to be undertaken by the AESO to
12 obtain project estimates for the various transmission solutions that would be sufficient for
13 confirming additional service to BC Hydro.

14 **6.5.2 AESO transmission losses**

15 Marginal losses for sending electricity to the FN/RB region (sending end loss percentages)
16 are very high. An approximation of the losses is as shown in Figure 6-2.

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Figure 6-2 Marginal Transmission Losses

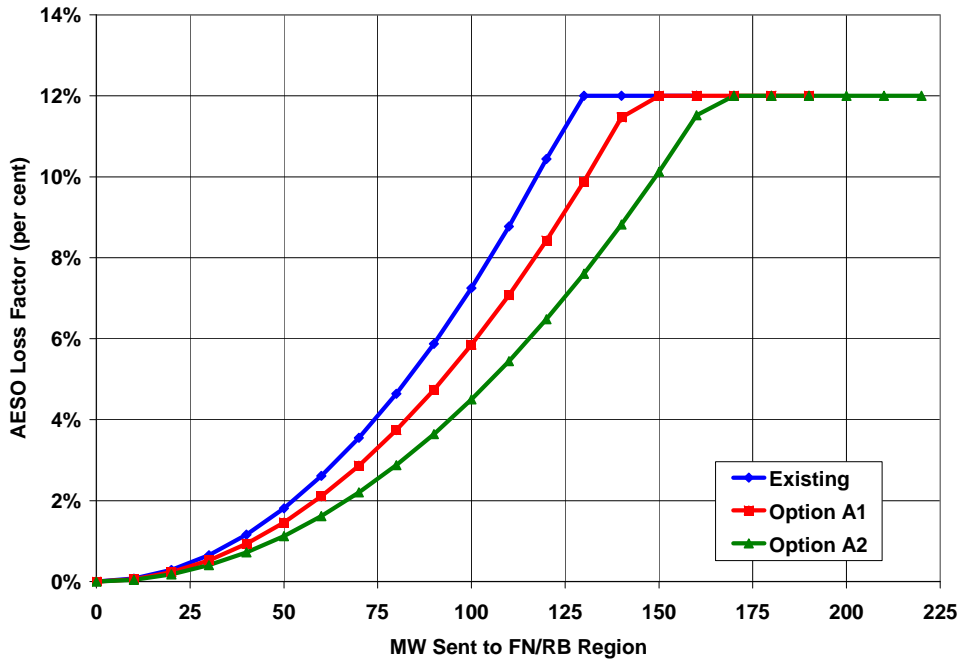


- 2 Transmission losses in the AESO are included in the transmission system costs as a Loss
 3 Factor for each location on the transmission system. The Loss Factor is based on a
 4 computation of the impact of incremental loads on average losses at each location for each
 5 year. The calculation is done annually and the Loss Factor is capped at +/- 12 per cent
 6 (sending end MW).³²
- 7 Estimates of Loss Factors for the base and two transmission options are presented in
 8 Figure 6-3.

³² Alberta Transmission Regulation, A.R. 86/2007

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Figure 6-3 AESO Loss Factors for FN/RB Region based on Supply to Region from Alberta System



4 The analysis in the 2008 FN RP includes both marginal loss analysis and analysis based on
 5 the annual AESO Loss Factor. The analysis assumes no generation in the Rainbow Lake
 6 region under normal conditions. For a combined load of 150 MW (forecast FN/RB region
 7 load in 2012 based on the Reference Forecast), the AESO Loss Factor would be
 8 12 per cent for the committed transmission and AESO A1 if there was no assumed
 9 generation in Fort Nelson.

10 In the case of Fort Nelson, the interconnection point to the AESO is measured at the border.
 11 This is the point that the AESO sets its Loss Factor with respect to Fort Nelson. BC Hydro
 12 assumed the losses from the border to Fort Nelson are four per cent for deliveries in either
 13 direction.

14 The average of the total losses from each scenario tested is reported in the economic
 15 analysis. Any dispatchable generation in Fort Nelson is assumed to be dispatched against
 16 the BC Hydro Electricity Price Forecast for the AESO adjusted for losses and GHG costs.

1 **6.5.3 Firming credit for SD 10**

2 Starting in 2016, a capacity firming charge/credit is calculated to reflect the relative impact
3 any supply portfolio may have on BC Hydro's requirement to be self sufficient by 2016. The
4 firming premium is the difference between the cost of firm supply for the integrated
5 BC Hydro system net of the relevant BC Lower Mainland electricity market price. The cost of
6 firm supply is calculated based on the annual capacity surplus or shortfall in the Fort Nelson
7 region (installed MW as compared to the annual peak demand) priced at BC Hydro's
8 Reference Price of \$88/MWh (Lower Mainland price in 2006 dollars) assuming a 65 per cent
9 load factor.

10 **6.5.4 GHG obligations on imports**

11 Energy purchased from the AESO is priced at the relevant electricity price scenario. As
12 described in section 2.3.3, the *GHG Cap and Trade Act* contemplates such a requirement
13 and leaves its implementation to regulation. Since such regulations have not been issued,
14 no adjustments have been made in the base analysis.

15 BC Hydro's current assessment is that any imports from Alberta would be from sources that
16 average in excess of 600 tonnes of CO₂e/GWh. Given that the BC Hydro Electricity Price
17 Forecast incorporates an assumption of offset requirements to 600 tonnes of CO₂e/GWh in
18 the case of Alberta, any GHG emission level above that level is already priced into the
19 market price forecast, and therefore into the base economic analysis provided in the
20 2008 FN RP/LTAP.

21 Given the increased likelihood of some offset requirement, BC Hydro has added a section in
22 its risk analysis that addresses the impact of such a requirement being in place by 2012.

23 **6.6 New Transmission interconnecting Fort Nelson to BCTC integrated system**

24 **6.6.1 Transmission Upgrade Option**

25 Interconnecting the Fort Nelson region to the BCTC interconnected system would require a
26 high voltage line, likely 230 kV, to be constructed from the Peace River region to Fort
27 Nelson. This line, called **BCTC B1** in the analysis, would be approximately 300 km in length.

1 This transmission distance to a major generating station is much shorter than the
2 comparable interconnection to the Alberta system.

3 The early investigation phase estimate of the line cost is \$403 million³³ and the expected
4 earliest ISD being by 2015. The loss factor to send electricity to Fort Nelson relative to the
5 BC Hydro Lower Mainland is expected to be -10.3 per cent (sending end loss calculation).
6 This is an incremental loss of 7 per cent from the Peace River region to Fort Nelson and a
7 loss credit of 16.1 per cent from the Lower Mainland to the Peace River region).

8 BC Hydro has requested that BCTC complete a planning level assessment with respect to a
9 new transmission connection between the Peace region and Fort Nelson. The study will (1)
10 focus on the physical interconnection options for a wide range in future regional load; (2)
11 recognize the current and planned generation and transmission facilities; (3) provide
12 transmission capability, schedule and cost estimates for identified options, and (4) consider
13 the issue of the ongoing interconnection with Alberta.

14 Construction of an interconnection to the main BCTC system may require the line from Fort
15 Nelson to Rainbow Lake to be operated in a normally open (disconnected) state. If this
16 option is selected, detailed system analysis would be required as part of further study to
17 identify operating constraints. The reliability of the new transmission line should be similar to
18 that of the line from Rainbow Lake to Fort Nelson. System reliability at the source end in the
19 Peace River region is much stronger than that at the Rainbow Lake substation.

20 **6.6.2 Capacity and Energy Supply associated with BCTC B1**

21 If a new transmission line to the BCTC interconnected system were to be the selected
22 solution, the incremental load to be served in the Fort Nelson area would need to be added
23 to the BC Hydro interconnected system load which would increase the capacity and firm
24 energy requirements of the interconnected system.

25 For supply planning, it is assumed that any capacity surplus or deficit in the Fort Nelson
26 region would require or allow an offsetting amount of firm supply on the BC Hydro integrated
27 system. The cost of the firm supply is calculated based on the annual capacity surplus or

1 shortfall priced at BC Hydro's Reference Price of \$88/MWh (Lower Mainland price in 2006
2 dollars) assuming a 65 per cent load factor.

3 For the portfolios based on the BCTC interconnection, any dispatchable generation in Fort
4 Nelson is assumed to be dispatched against the B.C. Lower Mainland Electricity Price
5 Forecast adjusted for losses unless required as must run generation.

6 7 Option/portfolio analysis

7 7.1 Analytical approach and Portfolio Construction

8 Each of the long-term solutions involves the acquisition of new capacity and energy from
9 one or a combination of the resource options identified in section 6. These resource options
10 generally would not be available until 2012. Therefore, there are two relatively distinct time
11 periods:

- 12 • the short-term where the plans are based on making the most of the assets that
13 currently exist; and
- 14 • the planning horizon where any of the resource options could be available to meet
15 any gap (shortfall) in BC Hydro's load/resource balance in the region.

16 With respect to the former, there is a probability that there will be insufficient supply
17 resources to reliably meet all requested load additions. The approach taken is to identify the
18 options available to BC Hydro to manage the load growth and acquire any incremental
19 transmission capacity as it becomes available from the AESO until new resources can be
20 made available. No trade-off analysis is provided for the period prior to 2011 as there is no
21 realistic alternative.

22 With respect to the latter, portfolios of resource additions are tested against the future load
23 scenarios. The analysis includes scenarios of future natural gas and spot market electricity
24 price forecasts.

³³ The transmission cost is based on the Northwest Transmission Line. That cost estimate is in 2013 dollars and includes costs for construction at 287 kV and the substation upgrades.